Ontario

Regulated Price Plan Manual

Ontario Energy Board

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NOTE TO READERS: The August 22, 2011 revisions to this Regulated Price Plan Manual generally update the Manual principally to reflect changes in law that have occurred since the Manual was revised in July, 2009.

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1. INTRODUCTION

About this Manual

Under amendments to the *Ontario Energy Board Act, 1998* (the "Act") contained in the *Electricity Restructuring Act, 2004*, the Ontario Energy Board (the "Board") is mandated to develop a regulated price plan (the "RPP"). The RPP replaced the electricity commodity pricing regime that went into effect on April 1, 2004, and took effect on April 1, 2005 for eligible consumers.[1]

This Regulated Price Plan (RPP) Manual (the "Manual") was initially prepared by the Board within the context of a larger regulatory proceeding (designated as RP-2004-0205) in which interested parties assisted the Board in developing the elements of the RPP.

This Manual describes the processes and methodologies that the Board uses to support its responsibilities with respect to setting prices under the RPP. The Manual is updated from time to time to reflect changes to those processes and methodologies and other relevant developments.

Implementation of the RPP by licensed distributors is addressed primarily in the Board's Standard Supply Service Code. The Standard Supply Service Code also contemplates that various elements of the RPP, including prices, will be determined in accordance with this Manual.

Related documents and Board decisions that describe processes and actions that other parties use to fulfill their responsibilities under or in relation to the RPP include:

Ontario Energy Board Instruments

- Retail Settlement Code (the "RSC");
- Standard Supply Service Code (the "SSS Code");
- Rate Orders; and
- Licences.

Independent Electricity System Operator (the "IESO") Instruments

- Ontario Market Rules.

Three other documents relate to the process for setting the RPP price, as described in this Manual:

[1] Consumers eligible for the RPP are identified in O. Reg. 95/05 (Classes of Consumers and Determination of Rates) (the "RPP Regulation").

- Ontario Wholesale Electricity Market Price Forecast, which contains the market price forecast used in the RPP price setting process.
- Regulated Price Plan Price Report, which describes the data sources for the forecasts and the application of the methodology in this Manual to arrive at the prices for the RPP.
- The RPP Regulation, which sets out who is eligible for the RPP and prescribes rules regarding the manner in which the Board determines rates for purposes of the RPP.

This Manual consists of six chapters as follows:

- Chapter 1. Introduction
- Chapter 2. Methodology for Calculating the RPP Supply Cost
- Chapter 3. Methodology and Timing for Setting RPP Prices
- Chapter 4. Methodology and Timing for Variance Tracking
- Chapter 5. Timing for RPP Price Adjustments or Price Structure Changes
- Chapter 6. Methodology for Determining Final RPP Variance Settlement Amounts

Purpose

The purpose of this Manual is to define and explain the methodologies and internal processes that the Board uses in determining electricity commodity prices that are charged to RPP consumers.

This Manual includes processes for calculating and setting the RPP prices, including separate prices for consumers that are charged on the basis of a tiered pricing structure (including consumers with conventional meters) and for consumers with eligible time-of-use (or "smart") meters that are charged on the basis of a time-of-use pricing structure; for monitoring and truing up variances between the forecast RPP price and the actual cost of RPP supply; for resetting the RPP price; and for calculating the final RPP variance settlement amount for consumers leaving the RPP.

In keeping with legislation, the RPP prices set by the Board are intended to reflect the cost of supply over time.

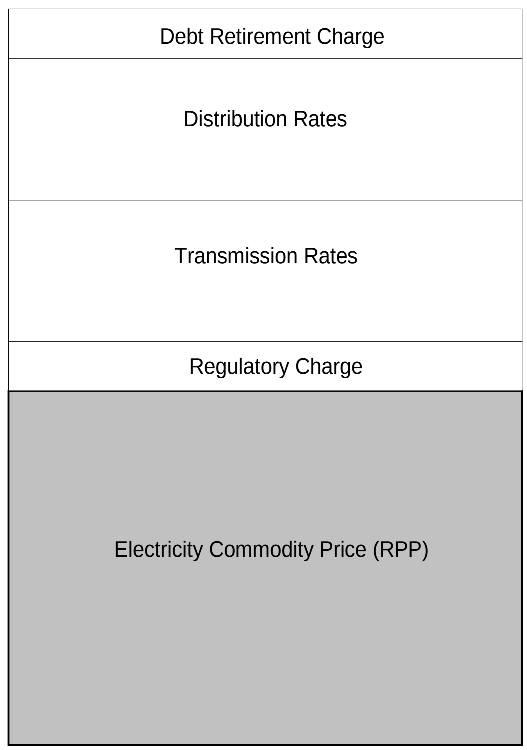
Authority for the OEB to Set RPP Prices

Section 79.16 of the Act assigns the Board responsibility for determining electricity commodity prices for eligible consumers. Consumer eligibility for RPP prices is determined by the RPP Regulation. The RPP Regulation requires the Board to forecast the cost of electricity used by these consumers and to ensure that the prices reflect that cost. The Act requires the Board to adjust RPP prices with a view to clearing any balances in the Ontario Power Authority (the "OPA") variance account over a 12-month period. As required by the RPP Regulation, the initial RPP commodity prices determined by the Board under both the tiered structure and the time-of-use structure were set to remain in effect for a period of at least 12 months (they remained in effect for 13 months, until May 1, 2006). Subsequently, the Board has reviewed and, where required, changed the RPP commodity prices every six months as discussed in Chapter 3.

Total Prices Paid by Consumers

The electricity commodity prices under the RPP comprise only one element of the total price paid by consumers taking RPP supply. Figure 1 shows the other elements that comprise the final retail consumer bill. The height of the bars in the diagram is roughly proportional to each element's relative share of the total retail electricity bill. There is also a brief description of each component of the consumer bill following the diagram.

Figure 1: Retail Electricity Price under the Regulated Price Plan



Electricity commodity price: This charge is for the electricity consumers use, which they buy either from their distributor at the RPP price or through a licensed electricity retailer at a contract price.

Regulatory charge: Regulatory charges are the costs of administering the wholesale electricity system and maintaining the reliability of the provincial grid.

Transmission charge: This component covers the costs of delivering electricity from the generating stations to the distributor along the high-voltage transmission system (also called the transmission grid). Transmission costs vary with the amount of electricity used.

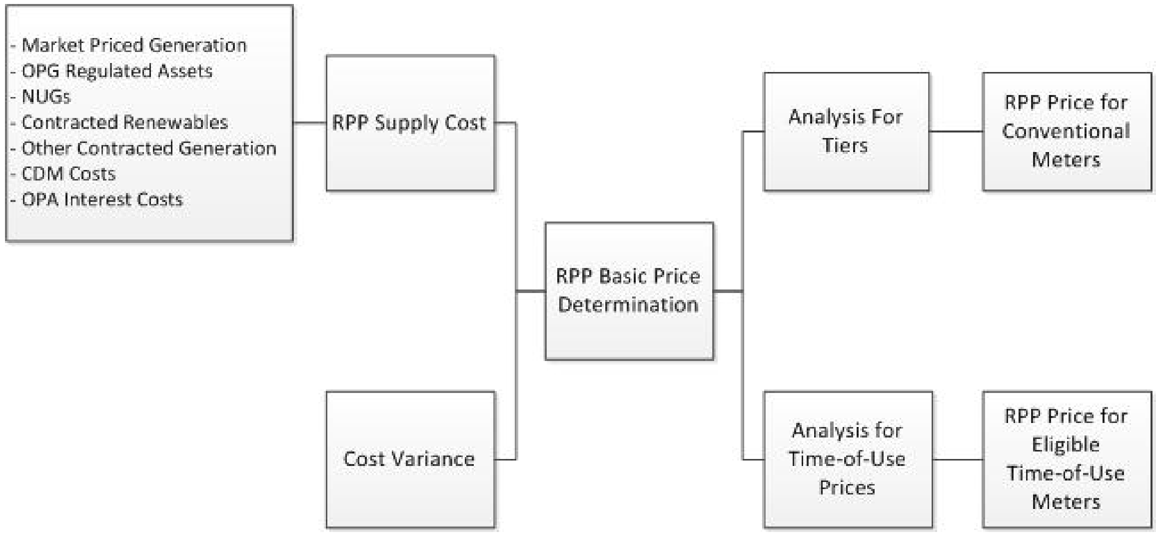
Distribution charge: This component covers the costs distributors incur in delivering electricity to the consumer's home or business. It includes fixed costs that do not change with the amount of electricity used. It also includes the costs of building and maintaining infrastructure, such as wires and hydro poles, which vary with the amount of electricity used.

Debt-retirement charge: This charge of 0.7 cents per kWh was set by the Ontario Ministry of Finance to pay down the residual stranded debt of the former Ontario Hydro.

Process for RPP Price Determinations

Figure 2 below illustrates the process for setting RPP prices and the decisions to be made in that process. The RPP supply cost and the accumulated variance between actual and forecast costs (carried by the OPA) both contribute to the base RPP price, which is set to recover the full costs of supply. The remainder of the process is also based on forecasts of prices and of consumption patterns. For consumers that are not being charged on the basis of time-of-use prices, the next step is to analyze the tier structure of their prices. From the tier structure is derived the RPP prices that such consumers will pay. For consumers with eligible time-of-use meters that are being charged on the basis of time-of-use prices, the next step is to analyze the pattern of prices in order to determine what the pattern of prices should be, both in terms of the three price levels (on-peak, mid-peak and off-peak) and in terms of the daily times of application of these prices. These differ seasonally.

Figure 2: Process for RPP Price



This Manual is organized according to this basic process. Chapter 2 describes the computation of the RPP supply cost. Chapter 3 explains the methodology used for setting RPP prices. Chapter 4 describes tracking and monitoring the Ontario Power Authority's variance account. Chapter 5 deals with the timing of price adjustments and price structure changes. Chapter 6 describes the methodology to be used for determining the final RPP variance settlement amounts for consumers that leave the RPP. Appendix A describes the equations used to determine the cost variance component of the process shown in Figure 2.

Using this Manual

The processes and methodologies in this Manual relate to activities of the Board and, for one particular function, to distributors with final RPP variance settlement responsibilities for RPP consumers. The Board uses these methodologies and processes to assist in determining electricity commodity prices for the RPP and to support the calculation of final RPP variance settlement amounts for consumers leaving the RPP. This Manual also serves as a guide to interested parties in understanding how the Board determines prices for the Regulated Price Plan.

Roles of Participants

This Manual describes the roles of various participants in or related to the RPP process, but does not directly place obligations on them. However, other instruments (such as the SSS Code) refer to this Manual with respect to some obligations, particularly the determination of the final RPP variance settlement amount for consumers leaving RPP supply. Requirements placed directly on participants are contained in legislation, regulations, licences, codes and the Market Rules, as applicable. The majority of RPP requirements and obligations for electricity distributors are set out in the SSS Code.

Roles of electricity distributors

Distributors are the point of contact, both physical and financial, for most consumers in Ontario's electricity system. They provide distribution service which allows electricity to be delivered to the place of consumption. Under section 29 of the *Electricity Act, 1998* (the "Electricity Act"), a distributor is also required to sell electricity to every person connected to the distributor's system, except those consumers that opt to purchase electricity from a competitive retailer. Other roles include:

- Meter reading;
- Billing;
- Electricity supplier for consumers taking RPP supply; and
- Electricity supplier for consumers not eligible for RPP supply and not taking supply from a competitive retailer.

Roles of the Independent Electricity System Operator (IESO)

The IESO's main role is to administer the wholesale electricity market in Ontario and to direct the operation of the IESO-controlled grid, scheduling and dispatching the electricity system to maintain safe and reliable electricity supply. It also settles the wholesale market with all wholesale market participants, both buyers and sellers. The IESO roles with respect to the RPP are:

- to include the global adjustment in its monthly settlements;[2] and

- to provide the Board with information as may be required by the Board for purposes of the determination of RPP prices and the final RPP variance settlement amount.[3]

Roles of the Ontario Power Authority (OPA)

The OPA is responsible for integrated system planning in Ontario, including forecasting electricity demand and supply adequacy and contracting for supply or demand management. With respect to the RPP, the OPA's roles are:

[2] The global adjustment was formerly also referred to as the "Provincial Benefit".
[3] Among others, section 23 of the Electricity Act states that "The IESO shall provide the Board, the OPA and the Market Surveillance Panel with such information as the Board, OPA or Panel may require from time to time".

- to hold in a variance account the amounts due to differences between actual electricity commodity prices and the forecast-based RPP prices; and
- to provide the Board with information as may be required by the Board for purposes of the determination of RPP prices.[4]

Roles of Ontario Electricity Financial Corporation (OEFC)

The Ontario Electricity Financial Corporation ("OEFC") is responsible for holding and defeasing that part of the former Ontario Hydro's debt that was not assigned to the successor operating companies. In conjunction with that responsibility, OEFC became the counterparty to the non-utility generator ("NUG") contracts signed by the former Ontario Hydro. As such, it is the metered market participant for the NUGs.[5] OEFC has also contracted with Ontario Power Generation Inc. ("OPG") to provide for the continued availability of two coal-fired generation facilities. OEFC's role with respect to the RPP is to provide the Board with information as may be required by the Board for purposes of the determination of RPP prices.

Prices

This Manual describes the methodology that the Board uses to determine commodity prices for RPP consumers, but does not contain the prices themselves. RPP prices, as determined from time to time, are posted on the Board's website**.**

Definitions

The following defined terms are used in this Manual.

> "Act" means the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, Schedule B;
>
> "Board" means the Ontario Energy Board;
>
> "consumer credit balance" means a balance in the variance account carried by the OPA for RPP consumers that will be credited to RPP consumers;
>
> "consumer debit balance" means a balance in the variance account carried by the OPA for RPP consumers that is owed to the OPA by RPP consumers;

[4] Among others, section 25.27 of the Electricity Act notes that "The OPA shall provide the Board with such information as the Board may require from time to time."

[5] OEFC is also the counterparty to contracts in relation to two additional generation facilities in respect of which contingency support payments to Ontario Power Generation (OPG) are made through the global adjustment. See O. Reg. 427/04 (Payments to the Financial Corporation re Section 78.2 of the Act) made under the Act, as amended effective January 1, 2009.

“conventional meter” means a meter other than an eligible time-of-use meter;

“Electricity Act” means the *Electricity Act, 1998*, S.O. 1998, c. 15, Schedule A;

“eligible time-of-use meter” means an interval meter or a meter that measures and records electricity use during each of the periods of the day referred to in section 3.4.1 of the SSS Code cumulatively over a meter reading period;

“final RPP variance settlement amount” means the amount charged or credited to an RPP consumer in accordance with section 3.7 of the SSS Code;

“global adjustment” or “GA” means the adjustment referred to in section 25.33 of the Electricity Act and made in accordance with regulations made under that section;

“IESO” means the Independent Electricity System Operator;

"Market Rules" means the rules made under section 32 of the Electricity Act;

“non-RPP consumer” means a consumer that is not an RPP consumer;

“Retail Settlement Code” or “RSC” means the code issued by the Board which, among other things, establishes a distributor’s obligations and responsibilities associated with financial settlement among retailers and customers and provides for tracking and facilitating customer transfers among competitive retailers;

“RPP consumer” means a consumer that pays the commodity price for electricity referred to in section 3.3 or 3.4 of the SSS Code;

“spot market price” means, for a given hour, the Hourly Ontario Energy Price established by the IESO for that hour; and

“Standard Supply Service Code” or “SSS Code” means the code issued by the Board and in effect at the relevant time which, among other things, establishes the manner in which a distributor must meet its obligation to sell electricity under section 29 of the Electricity Act.

Except as defined above, words defined in the Act, the Electricity Act or any regulations made under those Acts have the same meaning when used in this Manual.

2. METHODOLOGY FOR CALCULATING THE RPP SUPPLY COST

Introduction

This chapter describes and explains the methodology for computing the forecast RPP supply cost on which RPP prices are based. The methodology relies on forecast information that includes the results of a one-year Ontario market price forecast from a production cost model that produces forecasts of hourly prices and supply from specific generators.

The contents of this chapter are:

- Overview of the Ontario electricity market structure;
- Overall methodology for forecasting the RPP supply cost; and
- Computation of the RPP supply cost.

Currently, the production cost model used for forecasting purposes is maintained and run by a consultant under contract to the Board.

Overview of the Ontario Electricity Market Structure

The RPP is part of the structure for the Ontario electricity market created by the *Electricity Restructuring Act, 2004*.

There are principally four streams of generation sources for the RPP as identified in Figure 2: OPG's baseload and hydroelectric facilities; the NUG facilities; generation facilities under contract (including renewables); and market-priced generation (including imports). They are priced differently, and their pricing affects the RPP supply cost. This chapter details the methodology for the forecast of each of these cost elements and their integration into the RPP supply cost.

In the Ontario electricity market, while a part of the generation supply is paid a market-based price, the price for most of the generation supply is determined by contract, or regulation by the Board.

Overall Methodology for Forecasting the RPP Supply Cost

The supply cost of electricity provided to RPP consumers is determined in accordance with the rules established by legislation. The cost of electricity to wholesale customers is the amount they pay under the Market Rules (that is, the cost of their electricity at the hourly Ontario energy price or HOEP) plus, at the end of each month, an adjustment amount referred to as the global adjustment or "GA".

In the Ontario electricity market, certain contracted or regulated generators receive a final price that is different from the hourly market price as determined by the IESO. The IESO keeps track of these differences and adjusts the bills for all wholesale market participants to reflect them. The difference is included in the "global adjustment". The global adjustment is then passed through to all consumers of electricity.

The RPP supply cost is the cost of electricity supply for RPP consumers under the Market Rules, adjusted by cost factors relating to each of the other streams of supply and by certain costs that the OPA incurs to carry the RPP-related variance accounts. The costs of these streams are apportioned to RPP consumers in accordance with their share of total provincial electricity demand.

Equation 1 below shows the calculation of the RPP supply cost.

Equation 1

$C_{RPP} = M + \alpha\ [(A - B) + (C - D) + (E - F) + G] + H$, where

- C_{RPP} is the RPP supply cost;
- M is the amount that the RPP supply would have cost under the Market Rules;
- α is the RPP proportion of the total global adjustment costs;[6]

[6] The expression in square brackets is the global adjustment. "G" in the expression in square brackets integrates two separate components of the global adjustment formula (G and H) as set out in O. Reg. 429/04 (Adjustments under Section 25.33 of the Act) made under the Electricity Act.

Prior to January 1, 2011, the global adjustment was allocated to RPP supply costs according to the share of total Ontario load represented by RPP consumers, denoted here as α.

Effective January 1, 2011, O. Reg. 429/04 was amended to revise how global adjustment costs are allocated to consumers. O. Reg. 429/04 defines two classes of consumers: Class A, comprised of consumers with a maximum hourly demand for electricity in a month is 5 MW or more; and Class B consumers, comprised of all other consumers, including RPP consumers.

Therefore, as of January 1, 2011, α is defined as follows:

$\alpha = (RPP_d / \text{Class } B_d) \times 1/(1-\beta)$, where

β = the proportion of Global Adjustment costs attributed to Class A consumers;

- A is the amount paid to prescribed generators in respect of the output of their prescribed generation facilities;[7]
- B is the amount those generators would have received under the Market Rules;
- C is principally the amount paid to OEFC with respect to its payments under contracts with the non-utility generators (NUGs);[8]
- D is principally the amount that would have been received under the Market Rules for electricity and ancillary services supplied by those NUGs;
- E is the amount paid to the OPA with respect to its payments under certain contracts with renewable generators; [9]
- F the amount that would have been received under the Market Rules for electricity and ancillary services supplied by those renewable generators;
- G is (a) the amount paid by the OPA for its other procurement contracts for generation (both conventional and certain renewable) or for demand response or conservation and demand management ("CDM"), [10] and (b) the sum of any amounts approved by the Board for conservation and demand management programs approved by the Board that are payable by the IESO to distributors or the OPA;[11]and
- H is the interest paid to or earned by the OPA in relation to the RPP variance account.

RPP_d = the total load of RPP consumers;
Class B_d = the total load of Class B consumers.

[7] These are generators and generation facilities designated by regulation and whose output is subject (in whole or in part) to a rate set by the Board. Currently, these are OPG's baseload nuclear and hydro facilities identified in O. Reg. 53/05 (Payments under Section 78.1 of the Act) made under the Act.

[8] In addition to the contracts with the NUGs, OEFC is also the counterparty to a contingency support agreement with OPG in relation to two of its generation facilities identified in O. Reg. 427/04 (Payments to the Financial Corporation re Section 78.2 of the Act) made under the Act. Payments made to OPG under this agreement are related to the cost recovery mechanism associated with the CO_2 limits effective January 2009.

[9] These renewable generators are identified in O. Reg. 578/05 (Prescribed Contracts re Sections 78.3 and 78.4 of the Act) made under the Act.

[10] These contracts are identified in O. Reg. 578/05 (Prescribed Contracts re Sections 78.3 and 78.4 of the Act) made under the Act.

[11] As discussed below, these amounts relate to electricity distributor CDM programs that have been approved by the Board pursuant to a directive issued under section 27.2 of the Act (establishing CDM targets for electricity distributors). Recovery of these amounts through the global adjustment is contemplated in section 78.5 of the Act and in O. Reg. 429/04 (Adjustments under Section 25.33 of the Act) made under the Electricity Act effective January 1, 2011.

The forecast per unit cost of the RPP supply is C_{RPP} divided by the total forecast energy demand of RPP consumers. RPP prices are based on that forecast per unit cost. For that per unit cost forecast, all the terms in Equation 1 must be forecast. The remainder of this chapter describes the methodology for forecasting these terms, the average per unit cost of RPP, and the methodology for setting the base RPP price.

In developing this methodology, the Board took into consideration the use of the forecast and the relative value of increased precision. Deviations of actual from forecast RPP price are, under the Act and the Electricity Act, accumulated by the OPA in a variance account and collected from or remitted to consumers taking RPP supply through future price adjustments. Since there will inevitably be deviations (positive and negative) from the forecast, an increase in precision of the forecast only reduces the size of the variance. Given that some forecast inaccuracy is inevitable due to the large number of variables, the Board has chosen to use reasonable approximations for some calculations, rather than to aim for greater precision at higher, unjustifiable costs.

Computation of the RPP Supply Cost

Broadly speaking, the steps involved in forecasting the RPP supply cost are:

1. Forecast wholesale electricity market prices;
2. Forecast the load shape for RPP consumers;
3. Forecast the quantities in Equation 1; and
4. Forecast RPP Supply Cost = Total of Equation 1.

The methodology for forecasting the RPP supply cost describes each term or group of terms in Equation 1 and the methodology for forecasting them.

Cost of Supply Under Market Rules

This section covers the first term of Equation 1:

$$C_{RPP} = \boldsymbol{M} + \alpha\ [(A - B) + (C - D) + (E - F) + G] + H.$$

The cost of supply under the Market Rules depends on when any particular supply offer is accepted, dispatched and delivered to the grid to meet the last unit of instantaneous Ontario load on the grid. Peak period prices, representing higher marginal cost supply sources, are higher than off-peak period prices. The differences are large enough that ignoring them can introduce errors into the forecast of total RPP supply cost.

The pattern of electricity demand over time is called the load shape. If RPP consumers as a group had a load shape that is close to the overall load shape of the Ontario market as a whole (the system load shape), then a reasonable approximation of their total cost would be to assume that the average market price for this supply is equal to the overall system load-weighted average market price, and the market-based RPP supply cost would then simply be the total energy demand of the RPP consumers times the overall system load-weighted average hourly price.

However, different classes of consumers in Ontario have noticeably different load shapes. Industrial consumers tend to have much flatter load shapes; that is, they tend to use electricity much more evenly over the course of a day and over the seasons. Residential and small commercial consumers, who are the majority of the RPP-eligible consumers, have a load shape with a larger fraction of their demand occurring at peak times (winter mornings and late afternoons, and summer afternoons), as they use electricity for lighting, cooking, heating and air-conditioning.

Prior to obtaining more accurate hourly load data, RPP prices were initially established based on an approximation widely used called the Net System Load Shape, or NSLS. Each distributor's NSLS is its total load shape minus the load of consumers with interval meters whose hourly usage is recorded. The system-wide NSLS had previously been developed from a representative sample of net system load shapes from distributors across the province. However, the NSLS is no longer used by the Board. Instead, the forecast load shape of RPP consumers is based on historic hourly RPP consumer load data for virtually all Ontario electricity distributors from the Board's Cost Allocation Review process (EB-2005-0317). Load shapes change very slowly, so this is a reasonable approximation.

The value of M in Equation 1 is therefore the cost at market price of the total demand of the RPP consumers, computed using the weighted average load shape. The computation is performed using the production cost model's forecast of hourly prices multiplied by the forecast of hourly demand of RPP consumers. The forecast of hourly demand is obtained by applying the load shape to the total RPP demand forecast.

Cost Adjustment Term for Prescribed Generation Facilities

This section covers the second term of Equation 1:

$$C_{RPP} = M + \alpha\, [\boldsymbol{(A - B)} + (C - D) + (E - F) + G] + H$$

The dollar amount that the prescribed generators would receive under the Market Rules (quantity B in Equation 1) for their prescribed generation facilities is approximated by their hourly generation multiplied by the Ontario market prices during those hours.[12] Forecasts of both of these variables are available from the production cost model. For the purpose of setting the RPP price and monitoring variances from it, this calculation

[12] Generators are actually paid by the IESO on the basis of five-minute market clearing prices.

produces a monthly aggregated forecast of payments under the Market Rules for generation from prescribed generation facilities.

The amount paid to the prescribed generators (quantity A in Equation 1) is the regulated price established by the Board under section 78.1 of the Act. The production cost model provides forecasts of the outputs of the prescribed generation facilities. Quantity A can therefore be forecasted by calculating the average price per MWh for the prescribed generation facilities times their total output per month in MWh that is subject to the regulated price.

Cost Adjustment Term for NUGs and Other Generation Under Contract with OEFC

This section describes the calculation of the third term of Equation 1:

$$C_{RPP} = M + \alpha\,[(A - B) + \boldsymbol{(C - D)} + (E - F) + G] + H$$

The amount that the NUGs would receive under the Market Rules, quantity D in Equation 1, is their hourly production times the hourly energy price. These quantities are available from the production cost model as an aggregate for the NUGs as a whole.

The amount that the NUGs receive under their contracts with OEFC, quantity C in Equation 1, is not publicly available information, although it is known that most of the contracts provide for on-peak and off-peak prices. The Board initially obtained from the agency responsible for administering the NUG contracts (currently OEFC) a forecast of average on-peak and off-peak prices for these generators and average output on a monthly basis. However, the OPA has since that time begun to publish monthly aggregate payments to the NUGs (back to September 2007). Although the details of these payments (amounts by recipient, volumes, etc.) are not public, the published information is now used as the basis for forecasting payments in future months.

OEFC also has a contingency support agreement with OPG to provide for the continued availability of two coal-fired generation facilities (Lambton G.S. and Nanticoke G.S.). This agreement is related to the carbon dioxide (CO_2) limits that began to apply to OPG effective January 1, 2009. Payments from OEFC to OPG are also recovered through the global adjustment, and are captured by this element of Equation 1.

Cost Adjustment Term for Certain Renewable Generation Under Contract with the OPA

This section describes the calculation of the fourth term of Equation 1:

$$C_{RPP} = M + \alpha\,[(A - B) + (C - D) + \boldsymbol{(E - F)} + G] + H$$

Quantities E and F in the above formula refer to certain renewable generators paid by the OPA under contract; notably, renewable generators contracted under Phase I and Phase II of the Renewable Energy Supply ("RES") Request for Proposals issued by the OPA. While the OPA has contracts with other renewable generators (such as under the former Renewable Energy Standard Offer Program or "RESOP" and the current Feed-in Tariff or "FIT" program), payments under these contracts are included as part of quantity G in Equation 1, in keeping with the manner in which they are treated for purposes of the regulation that governs the calculation of the global adjustment.[13]

Computing the amount that would be payable to the RES generators under the Market Rules, quantity F in Equation 1, requires knowing the quantity of electricity generated per hour and the hourly market price. The quantity of electricity generated in turn is a function of the size and type of the generator.

The size and generation type of these successful renewable energy projects are known, as are the weighted average prices under the contracts. The production cost model produces forecasts of their hourly output, drawing on available information on the technical capability of these types of generators (wind, biomass, small hydro) and wind regimes in Ontario and on information from the OPA.

Cost Adjustment Term for Other Contracts with the OPA and for Board-approved CDM Programs

This section describes the calculation of the fifth term of Equation 1:

$$C_{RPP} = M + \alpha\ [(A - B) + (C - D) + (E - F) + \boldsymbol{G}] + H$$

Currently included in G are the following:

i. generation facilities procured under the 2005 "Clean Energy Supply" RFP (including the Greenfield Energy Centre and St. Clair Power gas-fired facilities);

ii. the "refurbishment" contract with Bruce Power;

iii. the so-called "early mover" clean energy supply contracts;

iv. contracts issued under the former RESOP program;

[13] O. Reg. 429/04 (Adjustments under Section 25.33 of the Act) made under the Electricity Act.

v. certain other generation contracts (including those awarded through the Combined Heat and Power (CHP) RFP and the contract for supply from the Portlands gas-fired facility);

vi. various contracts for the supply of demand response or conservation and demand-side management;

vii. contracts issued under the FIT program; and

viii. amounts approved by the Board for CDM programs approved by the Board.

Generation Contracts

The contribution of generation under contract to the OPA to quantity G in Equation 1 depends on the size, type and technical capability of the generators, on market conditions, and on their contracts with the OPA. Only the contractual compensation contributes to quantity G.

In terms of information that is not publicly available, the Board obtains from the OPA information at an appropriate level of detail for purposes of enabling the Board to forecast the contribution of contracted generation to quantity G in Equation 1. With this and other relevant information (such as the forecast of market prices where applicable), the Board is able to forecast the contribution of the generation under contract to the OPA to quantity G in Equation 1.

With respect to supply from the Bruce generation facility, it is noted that the output from unit "B" is subject to a "floor" price contract with the OPA. The terms of this contract can at times result in lump sum repayments to the OPA that affect the RPP variance account balance. To the extent these lump sum payments were not forecast, they are accounted for through the variance account rather than as part of the supply cost, given the clawback provision in the contract applies in January, when triggered.

Other Procurement Contracts

The amounts paid by the OPA for these other procurement contracts are forecast as accurately as reasonable given information that is available from public sources as well as information provided to the Board by the OPA. The OPA provides forecast information on the total amount under contract for demand response and for conservation and demand management, which is the contribution of these contracts to quantity G in Equation 1.[14]

Demand response payments are given to specific market participants when they agree to reduce their demand at specific times. Since the OPA cannot know in advance when such demand response will be required or for what duration, it cannot provide advance information on the totals. Such demand responses are only required, however, at times of tight supply. The production cost model forecasts how frequent and how severe such periods of tight supply are likely to be. With these results and information on the demand response costs and capacity under contract, the Board estimates the contribution of demand response contracts to quantity G in Equation 1.

<u>Amounts for CDM Programs Approved by the Board</u>

Further to a directive issued to the Board under section 27.2 of the Act, electricity distributors are required by their conditions of licence to achieve certain conservation and demand reductions through the delivery of CDM programs. A distributor may meet its CDM target through: (a) the delivery of CDM programs that are made available by the OPA; (b) the delivery of CDM programs that have been approved by the Board; or (c) a combination of (a) and (b).

In accordance with section 78.5 of the Act and O. Reg. 429/04 (Adjustments under Section 25.33 of the Act) made under the Electricity Act, amounts approved by the Board (including performance incentives) for CDM programs approved by the Board pursuant to a directive issued under section 27.2 of the Act will be settled through the IESO and recovered through the global adjustment.

CDM amounts approved by the Board will be included as part of the forecast RPP supply cost based on the timing of payments by the IESO as determined by the Board under section 78.5 of the Act.

Cost for OPA Variance Account

This section describes the calculation of the sixth term of Equation 1:

$$C_{RPP} = M + \alpha\,[(A - B) + (C - D) + (E - F) + G] + \boldsymbol{H}$$

[14] Some costs incurred by the OPA in relation to conservation and demand management are not recovered through the global adjustment. These include overhead costs, as well as grants under the OPA's Technology Development Fund and grants awarded prior to 2010 under the OPA's Conservation Fund. These costs are recovered through the OPA's fees and are therefore not captured in determining the RPP supply cost.

The OPA incurs direct costs to carry the RPP-related variance account. The OPA must pay interest on any negative variances. The OPA also credits the variance account with interest earned on any positive balances. Interest amounts can be forecast using the forecast of variance over the year and an assumption of the interest rates the OPA would earn or pay, given its credit rating.

The OPA does not currently allocate any other specific operating costs to the administration of its RPP-related variance account.

Total RPP Supply Cost

The total RPP supply cost is calculated as the cost of the supply needed to meet the demand from RPP consumers, determined using Equation 1.

3. Methodology and Timing for Setting RPP Prices

Introduction

The diagram in Chapter 1 indicates that setting the base RPP prices integrates two price components. The forward-looking component is based on a forecast of the RPP supply cost, which is calculated as detailed in Chapter 2 of this Manual. The backward-looking component is set to recover the accumulated variance in the OPA variance account. Appendix A describes the equations used to determine the variance component. These two components are then added together to produce the average RPP price, which is referred to as RPA. This chapter explains the processes for calculating and integrating these two components of the base RPP prices. This chapter also describes the process and methodology for setting the tiered prices and seasonal price tiers for consumers that are not being charged on the basis of time-of-use prices, and time-of-use pricing periods (on-peak, off-peak and mid-peak) for those consumers with eligible time-of-use (or "smart") meters that are being charged on the basis of time-of-use prices.

The contents of this chapter are:

- Timing for RPP price setting;
- Setting the price component to recover the RPP supply cost;
- Setting the price component to true-up the RPP supply cost variance;
- Setting the average RPP price;
- Setting the prices for RPP consumers with conventional meters;
- Setting the prices and times of application for RPP consumers with eligible time-of-use meters; and
- Price true-ups for extraordinary circumstances.

Timing for RPP Price Setting

As required by the RPP Regulation, the initial RPP prices were set to be effective for no less than 12 months (they remained in effect for 13 months, until May 1, 2006). Subsequently, the Board has reviewed and, as required, reset the RPP prices every six months.

The price resetting determines how much of a price change is needed to recover both the forecast RPP supply cost and the accumulated variance in the OPA variance account over the next 12 months.

Setting the Price Component to Recover the RPP Supply Cost

The first step in the computation of the RPP price is the computation of the forecast RPP supply cost, as described in Chapter 2. The average RPP supply cost is simply the total forecast RPP supply cost for the forecast year divided by the total forecast energy demand of RPP consumers for the year. This price component is not set at the average RPP supply cost; however, it is adjusted to take account of random effects on the costs.

Correcting for the Asymmetry in Probabilistic Modeling

The actual RPP supply cost is subject to random variation from a number of factors. These factors include, among others, the availability of generation from the prescribed generation facilities,[15] the availability of generation from resources under contract to the OPA, the level of demand from consumers taking RPP supply (which varies with the weather), and the load shape of that demand.

By their nature, the probability distributions of some of these variables are asymmetric. For example, if the assumed capacity factor of a generator is 80%, then there is more possible downside (to 0%) than upside (to 100%). Some other variables have similarly skewed distributions.

Based on the above, probabilistic modeling of the variance of actual from forecast RPP supply cost shows that there is a higher probability that the actual RPP supply cost will be above its expected value than below it. This raises the probability that such variance will trigger the need for multiple mid-plan price adjustments. In order to reduce that likelihood, this component of the RPP price is chosen at a level that will make the expected value of the cumulative variance over the 12 months equal to zero after the price resetting. This computation, referred to as the stochastic adjustment, is performed using a probabilistic simulation of the system (Monte Carlo technique) to determine the size of the variance given assumptions about the level of price and the distributions of the variables that drive market price determination. The stochastic adjustment has remained relatively constant since the RPP was introduced adding about $1 / MWh to the RPP price.

The result of this computation is a price that will make the expected value of the variance of the cumulative *actual* RPP supply cost from the cumulative *forecast* of RPP supply cost equal to zero. That price is then the component of the RPP price intended to recover the forecast RPP supply cost over the RPP price-setting period. This price

[15] As noted earlier, this refers to those of OPG's regulated nuclear and baseload hydroelectric generation assets that are identified in O.Reg. 53/05 (Payments under Section 78.1 of the Act).

ensures that the forecast of the cumulative variance over the 12 months after the price is set will be zero.

Setting the Price Component to True-Up RPP Supply Cost Variance

The total RPP supply cost variance is the difference between the actual RPP supply cost in a year and the amount collected from RPP consumers during that year. This amount is accumulated and held by the OPA in a variance account, and is tracked and monitored monthly by the Board as described in Chapter 4 of this Manual.

The variance is forecast for each month of the RPP year. At the end of each month there will therefore be a *forecast* and an *actual* variance amount. The difference between these is called the *unexpected* variance for the month.

For an RPP year, the forecast cumulative variance is zero because the RPP price is designed to make it so. For any shorter period, the forecast cumulative variance will not be zero, since the variance is expected to display a seasonal pattern, with consumer debit variances expected to accumulate in the peak (winter and summer) seasons and consumer credit variances expected to accumulate in the shoulder (spring and fall) seasons. Only when there is an unexpected cumulative consumer credit or debit balance at the time of a price resetting will it mean that the price should be trued up to recover that deviation; that is, the relevant amount for the true-up is not the *actual* accumulated variance, but the accumulated difference between the *actual* variance and the *expected* variance. In other words, the amount to be trued up is limited to the *unexpected* variance.

This accumulated unexpected variance is to be recovered over the 12 months following the date of the price setting. The component of the RPP price for recovery of this accumulated unexpected variance is therefore the total of the accumulated unexpected variance divided by the forecast energy demand of RPP consumers over the succeeding 12 months.

Setting the Average RPP Price

The average RPP price is therefore the sum of these two components:

1. The *prospective* recovery of the forecast RPP supply cost; and
2. The *retrospective* recovery of the cumulative *unexpected* variance.

This average RPP price is denoted as "RPA".

The next steps in the price-setting process determine the prices to be charged to each group of RPP consumers; (i) those that are charged on the basis of tiered prices; and (ii) those that are charged on the basis of time-of-use prices. RPP consumers in the first category are those with conventional meters or those with eligible time-of-use meters that are served by a distributor that has not yet implemented time-of-use pricing. RPP consumers in the second category are those with eligible time-of-use meters that are served by a distributor that has implemented time-of-use pricing.

Setting the Tiered Prices

For RPP consumers that are not on time-of-use pricing, the Board has established a tiered pricing structure. The tier structure includes both the levels of the prices in the two tiers — $RPCM_{T1}$ (the price for consumption at or below the tier threshold) and $RPCM_{T2}$ (the price for consumption above the tier threshold) — and the threshold level of consumption at which the consumer's price will move from the lower to the higher tier.

The tier prices, $RPCM_{T1}$ and $RPCM_{T2}$, are the same for all RPP consumers. However, the tier thresholds are not the same at all times, as stated in section 3.3.2 of the SSS code.

The tier prices must be calculated so that the expected average price, calculated on a "tier load weighted" basis, equals the average RPP price, RPA.

Given the tier threshold, the amount of electricity expected to be priced at each tier can be estimated. For that estimation, the Board uses information showing how much electricity consumers purchase in each month at each of the tiers. That calculation assumes that the tier thresholds are the same for all RPP consumers.

The Board then calculates the tier prices by targeting a ratio of 0.8 cents between the upper and lower tier prices. This 0.8 cent ratio was selected when the Board initially set RPP prices based on the then-existing tiered price structure established by the government (the prices at that time were 4.7 cents for consumption at or below the tier and 5.5 cents for consumption above the tier). For the actual calculation, the Board uses information on monthly consumption volumes.

This Manual now addresses the threshold for *residential* consumers. Since November 1, 2005, and as contemplated in section 3.3.2 of the SSS Code, the threshold has changed seasonally, with two six-month seasons starting on November 1 and May 1. The tier thresholds for residential consumers have consistently been set at 1000 kWh per month in the winter season (November 1 to April 30) and 600 kWh per month in the summer season (May 1 to October 31). These thresholds were selected based on information regarding the amount of electricity that consumers use in each of the heating and non-heating months.

In establishing the seasonal tier structure for residential consumers, the Board considered the following as set out in the initial version of this Manual:

> Adjustment of the threshold for *residential* consumers during the heating season could help alleviate the potential for some consumers with electric space heating to be paying higher average prices. In the winter season, defined as November through April, the tier threshold will be set at a higher amount per month. In the rest of the year, the tier threshold will be lower by an amount that will keep the average annual RPP price for residential consumers equal to the average RPP price, RPA. Keeping the average price for residential consumers at RPA avoids cross-subsidies with non-residential consumers whose thresholds are not adjusted on a seasonal basis.
>
> Considerations in the choice of thresholds are the impact of the threshold on consumers and the need to maintain the average RPP price for residential consumers at the level of the average RPP price as determined in accordance with this chapter.
>
> Average residential electricity consumption in Ontario is about 10,000 kWh per year per household, or about 830 kWh per month. On average, residential consumers therefore currently take some of their supply at the higher price tier in each month. However, given seasonal consumption patterns, the majority of residential consumers do not exceed the 750 kWh threshold in shoulder months with low space conditioning requirements. Residential consumers using electric space conditioning - heating or cooling - will likely take a larger fraction of their supply at the higher tier in months with high space conditioning requirements.

For *non-residential* consumers, the threshold has been fixed at 750 kWh per month all year round. Although section 3.3.2 of the SSS Code contemplates that the Board may vary that threshold, to date it has not done so.

Setting the Time-of-Use Prices

This section explains the methodology for computing the prices for RPP consumers with eligible time-of-use (or "smart") meters that are being served by a distributor that has implemented time-of-use pricing. Time-of-use pricing is optional (at the discretion of the distributor) until the distributor's "mandatory TOU date", being the date on which the Board determines that time-of-use pricing is mandatory for those of the distributor's consumers with eligible time-of-use meters. An RPP consumer with an eligible time-of-use meter will continue to be charged tiered prices until the mandatory TOU date applicable to the consumer's distributor unless that distributor has elected to make time-of-use pricing available.

Time-of-use prices are set to make the forecast average price charged to consumers that are being billed on the basis of those prices equal to RPA, the average RPP price. The basic methodology for determining the time-of-use prices, the values of $RPEM_{OFF}$ (price during an off-peak period), $RPEM_{MID}$ (price during a mid-peak period), and $RPEM_{ON}$ (price during an on-peak period) is to use data from the forecast cost of RPP supply and the forecast demand for such consumers to determine a set of prices that reflects their supply cost and that averages to RPA.

Time-of-use prices differ according to the season and time of day. The level of these prices is connected to the times when these prices apply because the cost of supplying electricity varies according to when it is supplied.

Objectives and Choices

Setting time-of-use prices requires more steps and more decisions than setting tiered prices. The complexity arises from the requirement to set more prices and the time periods when these prices will apply.

One of the objectives of having time-of-use meters is to give consumers more precise price signals and incentives to respond to those price signals. Consumers that are billed on the basis of time-of-use prices see prices that differ during the day, reflecting relative costs of generation at different times and allowing consumers to benefit by shifting or changing their consumption in response. Similar to the tiered prices, time-of-use prices are fixed in advance in order to limit the consumer's exposure to supply price volatility and to provide all RPP consumers with predictable prices.

The objectives for the time-of-use pricing system include:

- Set prices to recover the full cost of RPP supply; that is, the price structure must, on a forecast basis, recover all of the RPP supply costs from the consumers who pay the prices;
- Set the price structure to reflect RPP supply costs; that is, the prices should reflect the differences in cost of supply at different times of the day and year;
- Set both prices and the price structure to give consumers incentives and opportunities to reduce their electricity bills by shifting their time of electricity use; and
- Create a price structure that is easily understood by consumers.

These objectives guide the choices to be made to determine the prices. Some choices are reflected in the SSS Code. The most important of these are that there are three price levels and that there may be two seasons. The choices not articulated in the SSS Code include:

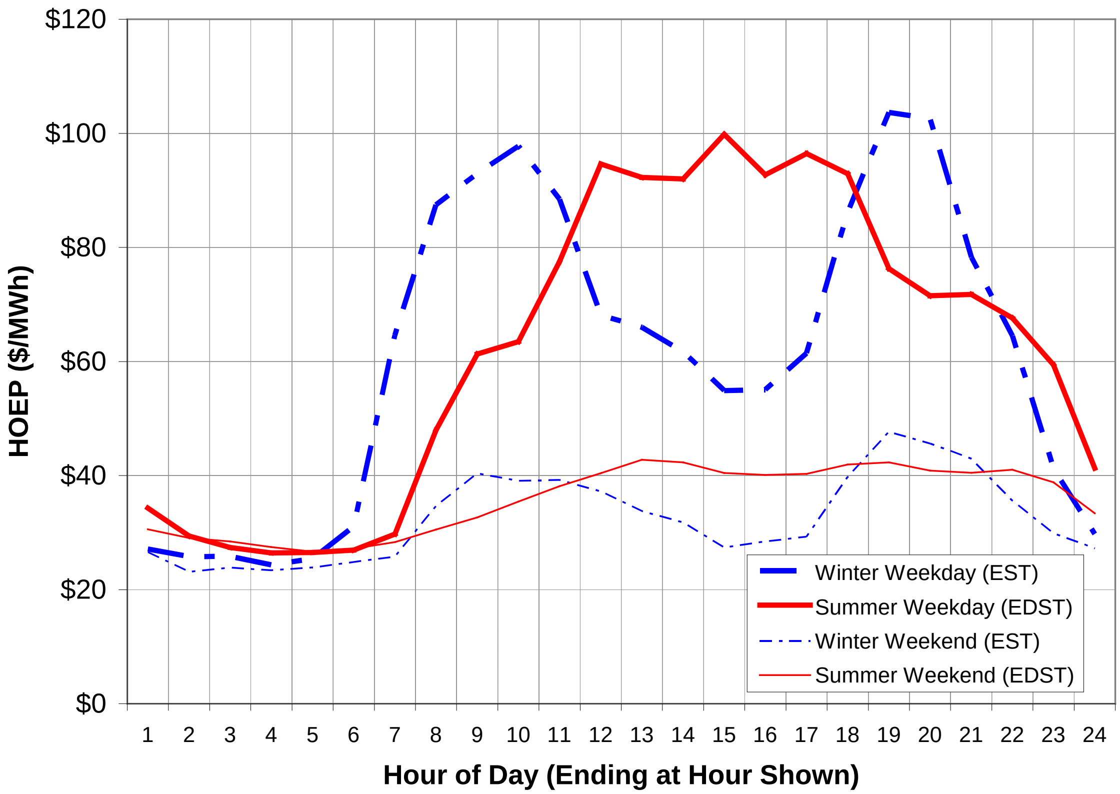
- The times of day at which the three price levels ($RPEM_{OFF}$, $RPEM_{MID}$, and $RPEM_{ON}$) apply:
    - Whether the times will differ in different *seasons* (and if so, how)
    - Whether the times will differ by *day* of the week (weekday vs. weekend); and
- The three price levels ($RPEM_{OFF}$, $RPEM_{MID}$, and $RPEM_{ON}$).

Determination of the Number of Time-of-Use Periods

The number of time-of-use periods should be chosen to further the objective of making the prices reflect the changes in supply costs over time in the Ontario electricity market. Since the prices are based on forecasts, the pattern of seasonal prices can also be based on forecasts. The number of time-of-use periods was initially determined by the Board based on the forecast of hourly HOEP, by season, for the first year of the RPP, as described in the initial version of this Manual:

> Figure 4 below shows the forecast of hourly HOEP, by season, for the first year of the RPP. Prices are the forecast HOEP for the hour of day ending at the hour shown on the horizontal axis. The price points are plotted in the middle of the hourly intervals shown and reflect the average HOEP during that interval. Note that the hours and the average HOEP for the summer season in Figure 4 have been adjusted for daylight savings time (i.e., times are given in Eastern Daylight Savings Time for the summer season and in Eastern Standard Time for the winter season).

Figure 4: Forecast Seasonal HOEP



Source: Navigant Consulting

The chart shows some consistency and some difference in the daily patterns of forecast prices in the two seasons.

Winter prices show a pronounced daily peak in the early evening hours, corresponding to residential and commercial lighting and space heating uses, and to residential appliance use. The winter evening peak price lasts from roughly 5 p.m. to 9 p.m. There is an almost equal peak period in the early morning hours, again reflecting commercial and residential lighting and space heating, and residential appliance use. The morning peak period lasts from about 7 a.m. to 11 a.m. While the highest prices in the morning are not as high as the highest evening peak prices, they are noticeably higher than those in the middle of the day. Winter therefore shows a noticeable daily double peak pattern.

In the *summer*, prices start to rise at about the same time as they do in the winter, about 7 a.m., but the most pronounced peak period is spread out over the afternoon, lasting from about 11 a.m. to 5 p.m. This corresponds to residential and commercial air-conditioning use on the hottest summer days. Accordingly, summer has a single daily peak period. The summer peak prices are close to those of the winter peak, though the averages are somewhat lower.

The pattern of off-peak prices is quite stable for both seasons. Demand falls off sharply after about 11 p.m., and picks up sharply at about 7 a.m.

These data also distinguish between *weekdays, weekends and holidays*. Weekends and holidays have much lower and much flatter forecast hourly prices because the overall demand is lower and the prices are therefore lower. Because the prices tend to be lower for whole weekends, the entire weekend can be defined as an off-peak period.

The choice of periods for different prices should reflect these patterns of market price, but need not directly replicate them. A price that varies too frequently would jeopardize the RPP goal of price stability.

The data indicate a consistent pattern of low, medium and high prices at specific times of the day and season. The data therefore support a three-price pattern.

More recent HOEP data shows that three-part market pricing is still evident, but that the spread between prices has decreased since 2004. This "price convergence" is consistent with the decrease in volatility in market prices that has resulted from improved supply-demand balances and greater reliance on long-term supply contracts. The Board's decision to allocate global adjustment costs non-uniformly (see below) is expected to mitigate the effects of this price convergence for RPP price-setting purposes. A time-of-use pricing structure that comprises three price periods remains appropriate.

Times of Application of Prices

The next issue is exactly what times to choose to apply the three prices. The time-of-use price periods were also initially determined by the Board based on the forecast of hourly HOEP, by season, for the first year of the RPP. Subsequent HOEP data shows similar patterns of daily and seasonal variation. All of the weekday prices ramp up rapidly at about 7 a.m., making that time the natural choice for the end of the off-peak period in both summer and winter. Prices ramp down in mid-evening in both winter and summer.

Over time, the Board has made certain changes to the time at which the off-peak period commences on weekday evenings in both winter and summer. In accordance with an amendment to the RPP Regulation,[16] effective May 1, 2011 the evening off-peak period must commence no later than 7 p.m.

[16] This amendment was made by O. Reg. 494/10, which came into force on January 1, 2011.

These considerations mean that the peak periods (both mid-peak and on-peak) should be from 7 a.m. to mid-evening (7 p.m.) on weekdays in both winter and summer. Off-peak weekday periods are therefore from mid-evening (7 p.m.) to midnight and midnight to 7 a.m.

The on-peak periods should reflect the times of distinctly higher prices. Winter has both morning and evening on-peak periods. The morning on-peak period lasts from about 7 a.m. to 11 a.m. or noon, and the evening from 5 p.m. to 8 p.m. or 9 p.m. Prices fall off to the mid-peak levels after 9 p.m., and stay there until they fall again after 10 p.m. or 11 p.m. A reasonable on-peak period for *winter weekday* mornings is therefore 7 a.m. to 11 a.m. Having regard to the amendment to the RPP Regulation referred to above, the *winter weekday* evening on-peak period should run from 5 p.m. to 7 p.m.

In the *summer*, the on-peak period for *weekdays* is from 11 a.m. to 5 p.m. The forecast data also show a similar pattern of prices, with a clear price break before and after those times.

Weekend hours have much the same daily pattern as weekday hours, except that prices tend to be flatter throughout the period from 7 a.m. to 10 p.m. Both the actual and forecast data show the highest weekend prices to be well below those of the weekday mid-peak periods. Giving *weekends and holidays* only off-peak prices would better reflect their cost conditions.

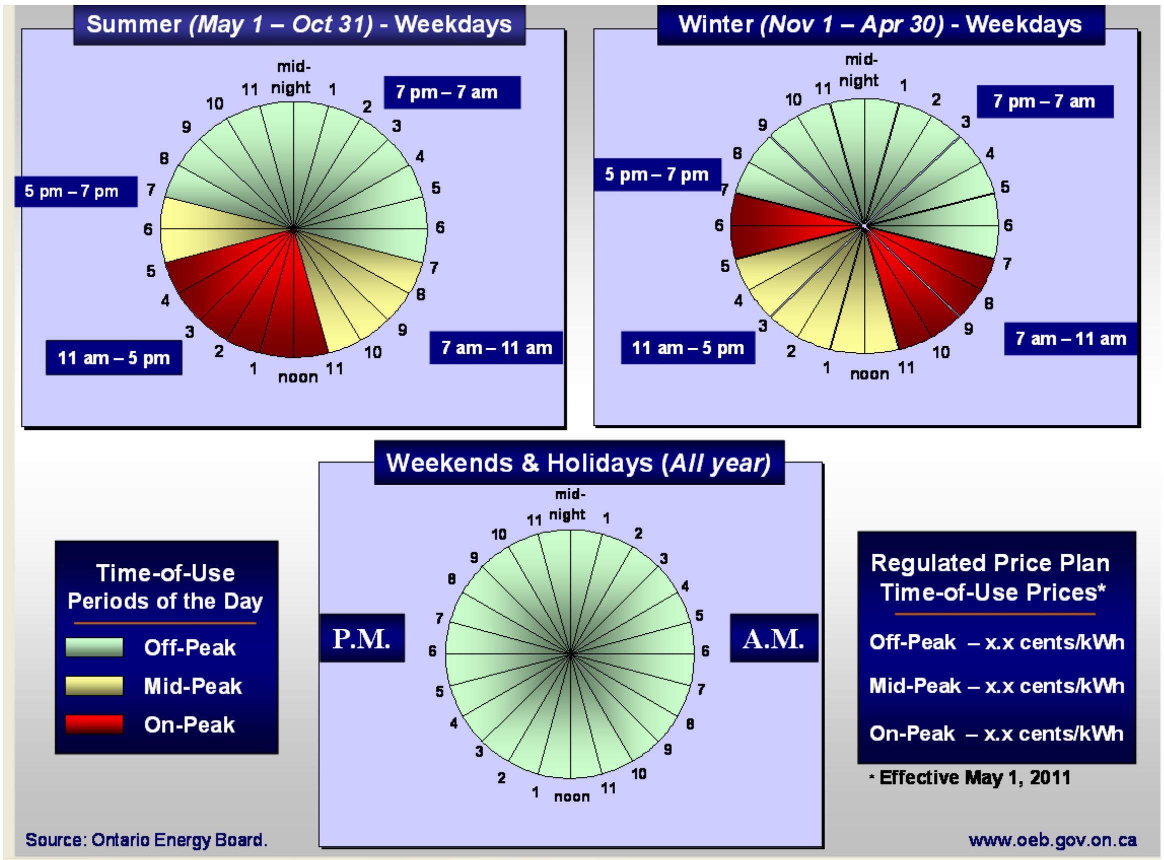
Taking these factors into consideration, the time periods for time-of-use (TOU) price application are defined as follows and as illustrated in Figure 5.

- *Off-peak* period (priced at $RPEM_{OFF}$):
  - *Winter and summer weekdays*: 7 p.m. to midnight and midnight to 7 a.m.
  - *Winter and summer weekends and holidays*: 24 hours (all day)
- *Mid-peak* period (priced at $RPEM_{MID}$)
  - *Winter weekdays (November 1 to April 30)*: 11 a.m. to 5 p.m.
  - *Summer weekdays (May 1 to October 31)*: 7 a.m. to 11 a.m. and 5 p.m. to 7 p.m.
- *On-peak* period (priced at $RPEM_{ON}$)
  - *Winter weekdays*: 7 a.m. to 11 a.m. and 5 p.m. to 7 p.m.
  - *Summer weekdays*: 11 a.m. to 5 p.m.

Times in the summer are "local" or daylight savings time.

For the purpose of RPP time-of-use pricing, a "holiday" means: *New Year's Day, Family Day, Good Friday, Christmas Day, Boxing Day, Victoria Day, Canada Day, Civic Holiday, Labour Day, and Thanksgiving Day*. When any such holiday falls on a weekend (Saturday or Sunday), the next weekday following (that is not also a holiday) is to be treated as the holiday for RPP time-of-use pricing purposes.

Figure 5: Times of Price Application (Effective May 1, 2011)



Establishing Prices

A basic requirement for TOU prices is that they must recover all of the expected costs of the supply; that is, they must average to RPA. They also should reflect the relative costs during the periods when they are being applied. Initially, the Board allocated global adjustment or "GA" costs uniformly on a per kilowatt-hour basis across all TOU supply. This allocation increased off-peak TOU prices proportionally more than on-peak prices, contributing to greater convergence between the three TOU pricing periods. The Board therefore determined that, commencing with prices set in the fall of 2009, the GA costs will be allocated to the TOU period when they are generated (in other words, GA costs associated with peak supply costs are recovered through peak TOU prices and similarly for off-peak and mid-peak supply costs and prices).

In addition, the load shape of consumers that are charged on the basis of time-of-use prices – and therefore the cost of supplying them – will change as they react to the prices themselves; the higher the differential between each of the on-peak, mid-peak and off-peak prices the more consumers can be expected to shift electricity usage.

For the calculations necessary to arrive at the TOU prices, it was initially assumed that consumers charged on the basis of those prices have the same load profile as those that are charged on the basis of the tiered prices. However, in 2008, enough data was available from time-of-use meters to begin using a load shape specific to consumers being charged on the basis of TOU prices.

To begin the calculation, the load profile of consumers on time-of-use pricing is used to calculate the supply cost for those consumers. This amount is analogous to the RPP supply cost of total demand of participating RPP consumers or quantity M in Equation 1 of Chapter 2. Then this amount is adjusted by the other components of Equation 1. This amount is the RPP supply cost for consumers on time-of-use pricing which must be recovered by the three prices. [17]

The key to setting these three prices is that they should reflect cost at their times of application, including the specific GA costs associated with each of the TOU periods. TOU prices are based on forecasts, as are the tiered prices. To determine TOU prices, the production cost model price forecast is analyzed to determine average price levels during the different times of application referred to in Figure 5. Then the process can set prices or price ratios to reflect costs. The forecast data show that the off-peak HOEPs are close to each other and stable in all seasons. The *off-peak* price is set at approximately the level of the average forecast off-peak price for both seasons of the year. Then the *mid-peak* prices can be set similarly (again reflecting forecast mid-peak prices that are close to each other and relatively stable in all seasons), leaving the *on-peak* prices to be determined. In addition, the Board may supplement the supply cost model forecast with an econometric model based on Ontario market data. This model may be used to determine an initial set of TOU prices which are subsequently adjusted so that these prices recover forecasted supply costs, including GA costs associated with specific TOU periods.

After any two of the prices are set, the third (on-peak) price is determined by the need for the forecast prices to fully recover the costs of supply, including the specific GA costs associated with peak supply. It is calculated as the price that will meet the forecast supply costs, given the load shape. The price so determined may or may not be fully

[17] Currently, the prices are set so that their load-weighted average is equal to RPA.

reflective of the average forecast price in the production cost model during the on-peak hours. Some adjustment may be needed to the other prices to produce a set of three prices that meets the criteria of recovering the forecast supply cost and of reflecting the average forecast prices during the hours of application of the prices.

The ratio of the prices has therefore been set in a way that reflects the relative forecast costs from the production cost model for the period for which the prices are being set.

An analysis of the forecast data for the first year of the RPP suggested that these prices would occur in the ratio of roughly 1:2:3. This is the relationship that appears in the average forecast prices from those forecasts. That is, the forecast price at the *mid-peak* times, corresponding to $RPEM_{MID}$, is roughly twice that at the *off-peak* times, corresponding to $RPEM_{OFF}$, and the forecast price at *on-peak* times, corresponding to $RPEM_{ON}$, is roughly three times $RPEM_{OFF}$.

In subsequent years, TOU price forecasts tended to converge, primarily the result of GA costs becoming a greater percentage of total supply costs and being allocated uniformly. In response to this trend and as noted earlier, since November 1, 2009 the Board has allocated GA costs non-uniformly according to when these costs are generated, i.e., during peak, mid-peak or off-peak hours. Subsequent price settings show that this type of GA cost allocation has offset some of the convergence trend and partially restored the 1:2:3 ratio that was assumed by the Board to be an adequate incentive for consumers to shift load.

Price True-Ups for Extraordinary Circumstances

Under some extraordinary circumstances, large unexpected variances (deviations) could accumulate in a short time. This could occur as a result of some major unanticipated event, such as a prolonged unexpected outage of a large generator. As described in Chapter 4 of this Manual, deviations of actual from forecast variances are tracked and monitored monthly. It might be desirable, under such extraordinary circumstances, to take prompt action to bring prices back towards cost to avoid the possibility of accruing undesirably large deviations and, as a result, unusually high price adjustments at the next scheduled RPP price adjustment date.

In general, it would be expected that such action would not be taken on the basis of one or two months' experience, but rather would be considered on a quarterly basis. Quarterly analysis smooths the more extreme variations of monthly results, and should therefore avoid making changes in reaction to a relatively short-term extreme event that does not recur.

For similar reasons, an interim true-up of this kind should only occur when there has been an extraordinary accumulation of deviations from the expected variance, as indicated by the unexpected variance exceeding a trigger value. Considerations in setting the trigger value include the impact on the consumer bill and the probability of such a high unexpected variance occurring.

Assuming roughly 4 million RPP consumers, the average cost per customer of a $40 million unexpected variance is about $10. That would have a bill impact of under $1 per month, if collected over 12 months. Variance modeling shows that an unexpected variance of about $40 million a month occurs less than 10% of the time. Choosing a trigger value of $160 million would produce an impact of approximately $40 per customer, and a bill impact of about $3.40 per month. Variance modeling suggests that random events would produce an unexpected variance of that magnitude in a single quarter less frequently than once in five years.

The *trigger value* is therefore set at $160 million. When an *unexpected* variance of $160 million or more accumulates over a quarter that does not conclude with a scheduled semi-annual true-up and rebasing, a price true-up will automatically be implemented in the form of an RPP price adjustment to begin to recover that variance. It is important to clarify that only the unexpected portion of the variance would be included in the RPP price adjustment at that time.

The price true-up will be calculated as the total unexpected variance divided by the total forecast RPP demand over the next 12 months.

This extraordinary case is the only time that a change in the RPP price is based solely on the need to recover accumulated deviations of the variance from the expected variance (i.e., only retrospective). All ordinary or scheduled RPP price adjustments are based on recovery of both the forecast RPP supply cost and the past accumulated deviations (i.e., both retrospective and prospective).

4. Methodology and Timing for Variance Tracking

Introduction

This chapter sets out the methodology and timing for tracking and monitoring the monthly balances[18] in the OPA variance account, carried for RPP consumers. The monthly variance balance held by the OPA is the difference between the actual RPP supply cost for the month and the revenues collected from RPP consumers for that month.

The *actual* monthly variance account balance is compared against the *expected* monthly variance account balance. This chapter describes the methodology and timing for the calculation of the forecast variance and for tracking deviations of actual from forecast variance. Chapter 3 describes the uses of this information for price rebasing and price true-ups.

The contents of this chapter are:

- Monthly Variances;
- Variance Forecasting;
- Variance Monitoring; and
- Frequency of Variance Monitoring.

Monthly Variances

For all RPP consumers, the RPP prices are set in advance for an entire forecast year. The prices reflect a forecast of average RPP supply cost for the forecast year, adjusted to collect any outstanding variance balance at the beginning of the period and to bring the expected annual cumulative variance balance as close as technically possible to zero.[19]

The actual RPP supply cost in each month can be expected to vary in a systematic way from the forecast average monthly RPP supply cost. This is because both price and demand conditions vary over the year. For example, in the shoulder months, market prices will tend to be lower than the annual average, producing a monthly RPP supply cost that is lower than its annual average. In the peak demand months, the market can

[18] This discussion is in terms of monthly variances because that is the frequency with which the OPA accumulates variance data.

[19] Due to the need to round RPP prices to a tenth of cent, it is not possible to bring the expected variance balance to exactly zero when prices are adjusted.

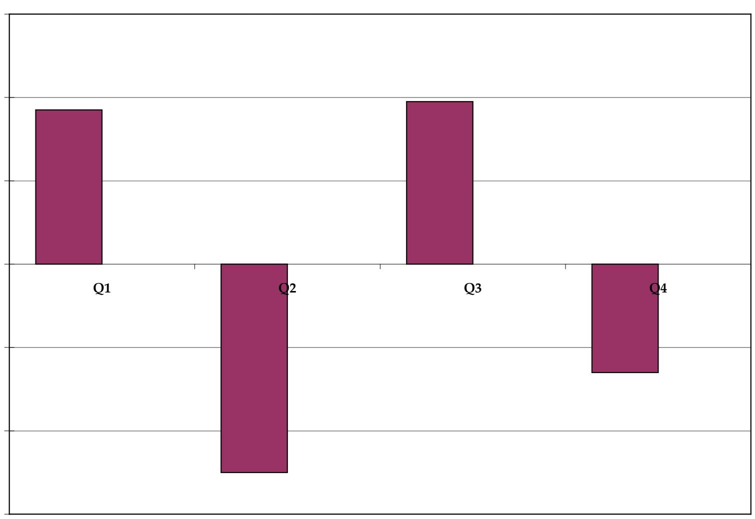
be expected to produce a monthly RPP supply cost that is higher than its annual average.

These considerations lead naturally to the expectation that, in the low-price months, a consumer credit balance can be expected to accumulate in the variance account; in the high-price months, a consumer debit balance can be expected to accumulate in the variance account. Although the average RPP price or RPA is chosen to produce a zero expected value of the cumulative variance over the year, the expected value of the variance in each month is not zero.

In addition to the normal seasonal trends in consumption patterns discussed above, the residential seasonal tier thresholds also need to be taken into account. While there is only technically a single average RPP price (or RPA), the residential threshold is higher in winter (1000 kWh) than in summer (600 kWh). This means that the average price most RPP consumers pay will be lower in winter than in summer, since they will have less consumption at the higher tiered price in the winter. Thus, variance clearance will vary from summer to winter. This factor has become more pronounced over time as many of the larger consumers, such as those in the MUSH sector (Municipalities, Universities, Schools and Hospitals), have exited the RPP either in anticipation or as a result of their ceasing to be eligible for the RPP on November 1, 2009 in accordance with the RPP Regulation.

The expected monthly variances can be aggregated into expected quarterly variances, with each quarter representing three months of RPP supply. Figure 6 provides an illustrative example of the possible expected quarterly variances over a single RPP year.

Figure 6: Illustrative Expected Quarterly Variances



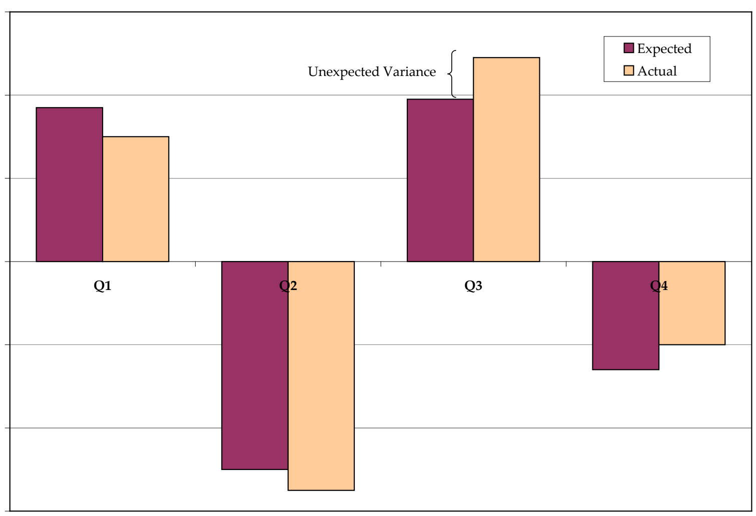
The *actual* RPP supply costs are not expected to exactly match the *forecast* RPP supply costs, in any given month or quarter, nor are *actual* RPP revenues expected to exactly match *forecast* RPP revenues. These differences will create an "unexpected" variance. The term unexpected is used to differentiate this from expected variances that can be forecast based on expected monthly and seasonal consumption and supply cost patterns. The unexpected variance in a given period is simply the difference between the actual RPP revenue and the actual RPP supply cost less the expected variance for the period.

In mathematical terms, the unexpected variance for a given period can be defined as follows:

Unexpected Variance = Actual RPP Revenue - Actual RPP Supply Cost - Expected Variance

This is illustrated in Figure 7. In the illustration, the actual variance in the third quarter is greater than the expected variance and the difference between the actual variance and the expected variance is the unexpected variance.

Figure 7: Illustrative Unexpected Quarterly Variances



For the purpose of considering changes in the RPP price, the size of the variance must be monitored. Variances must be trued up so that the actual cost of RPP supply is recovered over time, as required under section 79.16 of the Act and the RPP Regulation. However, in monitoring the monthly variance, the quantity to be monitored is not the actual variance itself but the unexpected variance in that month. The unexpected variance can be summed over the periods in the year to determine the cumulative unexpected variance. Provided the forecast cumulative expected variance at the end of the RPP period is zero, the cumulative unexpected variance at the end of the year represents the amount that would be trued-up in the next RPP period.

Variance Forecasting

The methodology for setting RPA requires modeling variances of the actual RPP supply cost from the forecast RPP supply cost, in order to determine RPP prices that set the expected variance as close as possible to zero. For that purpose, a probabilistic model is constructed which models the events that can produce variances from the forecast RPP supply cost, given assumptions about the probability distribution of the key driving variables. The model results are then used to establish the expected value of the variance. This variance model is the basis for the forecast of expected monthly variances.

A monthly variance forecast is produced every six months each time that RPP prices are reset because variance modeling is done at that time. The variance forecast uses monthly forecasts of the variables driving the monthly RPP supply cost. These variables include electricity demand and generation availability. These factors are taken at their values from the production cost model, either as inputs to or outputs from that model. The variance model also takes account of the historical volatility of HOEP. These values are then used to produce forecasts of the monthly variance.

Variance Monitoring

Two variance totals are calculated and monitored. The first is the cumulative actual variance, as seen in the variance account of the OPA. That amount is the cumulative difference between the actual RPP supply cost and the revenues collected from RPP consumers. It is the amount that must ultimately be collected from consumers, if it is a consumer debit, or paid to them if it is a consumer credit.

However, as noted above, recovering that cumulative actual variance amount may not require any additional action. If the cumulative actual variance in any month is the amount forecasted for that month, it will be expected to be offset by variances in the opposite direction in the coming months so that it will be zero by the end of twelve months from the time of price resetting.

For considering true-ups the relevant amount is therefore the unexpected variance. The monthly unexpected variance is monitored for information and to understand trends. The unexpected variance is also accumulated into a quarterly total (as illustrated in Figure7). The quarterly cumulative unexpected variance is also monitored for its potential to trigger an extraordinary true-up, as described in Chapter 3.

The total cumulative unexpected variance is the amount to be trued up, as described in Chapter 3 of this Manual. Appendix A describes the equations used to determine the total cumulative unexpected variance.

Frequency of Variance Monitoring

The process described above occurs monthly. The actual cumulative variance is available on a monthly basis from the OPA, and the Board performs the steps listed in this chapter to monitor its deviation from the forecast for that month.

Although the monitoring is monthly, the decision on price resetting and true-ups, as described in Chapter 3 of this Manual, is taken every six months. There is also provision for a true-up as an extraordinary event if the quarterly unexpected variance exceeds a trigger level.

5. Timing for RPP Price Adjustments or Price Structure Changes

Introduction

This chapter sets out how long in advance new RPP prices or changes in RPP price structure will be determined by the Board prior to the date on which the new prices or structure are to come into effect. This reflects the period of time that distributors will have to implement price level or price structure changes and can be considered as a notification period to distributors. The time periods discussed below are consistent with section 3.8 of the SSS Code, which contains provisions that require distributors to notify RPP consumers of RPP price or price structure changes.

New RPP prices are computed at six-month intervals and are the result of an integrated consideration of re-basing and true-ups. Price changes become effective at the beginning of a calendar month.

The contents of this chapter are:

- Timing of Notification of Price or Price Structure Change; and
- Timing of Implementation by Distributors.

Timing of Notification of Price or Price Structure Change

Most RPP price changes will adjust only the RPP price level(s). For such changes, distributors require a minimum of about 30 days of lead-time before customers can be billed based on the new RPP price. Since distributors do not start to send out bills to consumers based on the new price until about 15 days after its implementation, the 30-day distributor lead-time is achieved by setting the new prices at least 15 days before the beginning of the month in which the new prices are to be implemented. New prices are therefore set (and distributors are thus informed) at least 15 days before distributors begin charging those new prices to consumers. This applies to changes in any RPP price, namely, to changes to any of $RPCM_{T1}$, $RPCM_{T2}$, $RPEM_{OFF}$, $RPEM_{MID}$, and $RPEM_{ON}$. This also applies to price changes that are intended to true-up prices as a result of extraordinary circumstances, as described in Chapter 3.

Changes to the RPP price structure include changes to tier thresholds[20] and any other change affecting an RPP element other than the price level(s). For changes to the RPP price structure, distributors require 90 days of lead-time, or 75 days before the changes are to be implemented. Therefore, structural changes are determined by the Board (and distributors are thus informed) at least 75 days before their implementation date.

Timing of Implementation by Distributors

Distributors will charge RPP consumers based on new RPP prices or a new RPP price structure for consumption on and after the first day of the month of implementation. For most RPP consumers, the first day of the month will not correspond to a meter reading, so the SSS Code permits distributors to pro-rate for the billing period within which the price or price structure change takes effect. The method to be used by distributors for proration is set out in the SSS Code.

[20] This does not include the normal seasonal change in the residential tier threshold (600 kWh per month in the summer and 1000 kWh per month in the winter).

6. Methodology for Determining Final RPP Variance Settlement Amounts

Introduction

This chapter explains the methodology to be used by distributors to compute final settlement variance amounts for RPP consumers leaving the regulated price plan. This is the methodology referred to in section 3.7.1 of the SSS Code.

As shown in Figure 2 of Chapter 1, the OPA carries a variance account representing the accumulated difference between the actual RPP supply cost and the revenues collected from RPP consumers. Consumers who do not leave the RPP will pay or receive the benefit of the accumulated variance over the next 12 months through the component of the RPP price that reflects past variances,[21] as described in Chapter 3 of this Manual. However, once consumers leave RPP supply,[22] they no longer pay RPP prices and therefore no longer pay or receive the benefit of their share of past cumulative variances. For that reason, these consumers will be responsible for a final RPP variance settlement when they leave RPP supply since the RPP price determination assumed that they would have remained on RPP for the full 12 months.

The final RPP variance settlement amount could be positive or negative. In other words, depending on the status of the variance account held by the OPA, the consumer could either receive a payment (i.e., credit) or be required to make a payment (i.e., debit).

The contents of this chapter are:

- Determination of Final RPP Variance Settlement Amount and Rate; and
- Final RPP Variance Settlement Amount Calculation.

Determination of Final RPP Variance Settlement Amount and Rate

The variance amount that is the basis for the final RPP variance settlement is the cumulative variance held by the OPA, referred to in Equation 2 below as CV_t. That cumulative total is the total variance of the actual RPP supply cost from the revenues

[21] RPP consumers are also responsible for paying any interest costs incurred by the OPA in relation to the variance account. A consumer leaving the RPP is also responsible for a share of these interest costs. Equation 2 takes into account that such costs are reported monthly to the Board and are added to the variance that is reported to the Board by the IESO each month.

[22] That is, move out of Ontario, switch to the spot market option or to a competitive retailer, or cease to be eligible for the RPP.

collected from RPP consumers. It is therefore the amount that will be collected or credited in the future from or to consumers remaining on RPP supply. It will be collected from or credited to them in the future through the RPP prices they pay. When consumers leave RPP supply, they will not be paying RPP prices and therefore will no longer be paying or receiving the benefit of any of that cumulative variance. The amount the individual consumer would be responsible for or entitled to will therefore be estimated, and recovered or paid, by the distributor at the time of leaving RPP supply.

To facilitate this variance account settlement procedure, the IESO reports monthly to the Board on the accumulated balance in the OPA's RPP variance account. In addition, the OPA reports the accrued interest on the RPP variance account. The Board converts the sum of these amounts into a per kWh variance recovery amount (referred to in Equation 2 below as V_{FS}) for final settlement by dividing the total accumulated variance by the actual total RPP consumption in the preceding 12 months. The per kWh variance amount is communicated by the Board to the distributors to use in final settlement and is also made public on the Board's web site. This communication and web site posting is done on or around the 15th of each month.

The calculation of this per kWh variance amount is given in Equation 2 below:

Equation 2

$$V_{FS} = CV_t / D_{12}$$

Where V_{FS} = the variance amount for final RPP settlement, per kWh

CV_t = cumulative variance total in the OPA account at the end of month t; and

D_{12} = the total consumption from RPP consumers over the 12 months before (and including) month t.

V_{FS} expresses the cumulative variance on a per unit basis for the most recent 12 months prior to leaving the RPP, and is an approximation of the rate at which any RPP consumer would make payments towards the cumulative variance.

For consumers that remain on RPP, the expected portion of the cumulative variance will be recovered through RPP prices over the remainder of the RPP term and the unexpected portion of the cumulative variance will be recovered when prices are trued-up. The amount per kWh that will be recovered is the cumulative variance divided by the forecast of total RPP consumption over the year. The variance settlement for the consumer who leaves RPP supply will similarly represent the total payment that would have been made over the year. Since there is no forecast of that consumer's expected demand over that year, consumption over the previous year is used as an estimate.

Final RPP Variance Settlement Amount Calculation

The final variance settlement process collects or credits an appropriate amount from a consumer leaving RPP supply. The amount to be collected or credited in relation to a given consumer is V_{FS} times that consumer's actual consumption over the preceding 12 months, determined as discussed below.

In general, a distributor will not have a precise total for the consumer's actual consumption over the exact 12-month period before the date on which the consumer leaves RPP supply. Whether from a final meter read or a pro-rated estimate, the distributor will have final consumption data for the final bill. The distributor may not have a corresponding meter read for a period of exactly 12 months before the final billing date because many distributors read meters on a bi-monthly schedule. However, distributors do retain meter reading history for at least a year, so they do have total metered consumption by the consumer for some previous 12-month period.

In the absence of actual consumption information, a distributor must reasonably estimate the consumer's consumption over the previous 12-month period. This must be done by using actual meter readings to the maximum extent possible and interpolating to get an estimate of what the meter reading would have been on the date exactly 12 months prior to the final meter read.

This allows for a fair approximation of the actual amount that the consumer would have been responsible to pay or would have received the benefit of had the consumer remained on RPP supply, while not burdening the distributor with the unduly complex data maintenance or computational requirements associated with a more precise determination.

A distributor must collect or credit this final RPP variance settlement amount from each consumer leaving RPP supply under the conditions described in section 3.7.1 of the SSS Code. For this amount then to be properly credited to or debited from the OPA variance account, it must be reported to the OPA under procedures established by the OPA and the IESO.

APPENDIX A: TRUE-UP EQUATIONS

This appendix describes the equations used to determine the cost variance component of the process shown in Figure 2 on page 5.

The actual variance is always calculated as a cumulative total,

(1) $CV_{t+1} = CV_t + V_t$,

Where CV_{t+1} = actual cumulative variance in time t + 1,
CV_t = actual cumulative variance in time t, and
V_t = actual variance in time t as reported by the IESO.

The cumulative forecast variance is also always calculated as a cumulative total,

(2) $FCV_{t+1} = FCV_t + FV_t$,

Where FCV_{t+1} = forecast cumulative variance in time t + 1,
FCV_t = forecast cumulative variance in time t
FV_t = forecast variance in time t.

Then the unexpected variance in time t is

$UV_t = FV_t – V_t$

Where UV_t = the unexpected variance in time t.

The cumulative unexpected variance is

$UCV_{t+1} = UCV_t + UV_t$

Where UCV_{t+1} is the cumulative unexpected variance in time t+1.

The amount to be trued-up is then always the cumulative unexpected variance at the time of true-up, or UCV_6 for a true-up at 6 months.